COMPARATIVE EVALUATION OF
ELECTRIC POWER PLANT SITING REQUIREMENTS
IN WASHINGTON, OREGON AND CALIFORNIA

Prepared for

ENERGY DIVISION
OFFICE OF TRADE AND ECONOMIC DEVELOPMENT
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1. EXECUTIVE SUMMARY

The margin between electricity supply and demand has narrowed in the Pacific Northwest in recent years. Historically, the Northwest experienced its peak electric loads during the cold, winter months; the Southwest experienced its peak electric loads during the hot, summer months. When supplies were more plentiful and hydroelectric resources were less constrained, the Northwest was able to export electricity to the Southwest in the summer; the Southwest was able to reciprocate in the winter. Due to existing supply constraints in Washington, Oregon and California, some time may pass before resumption of these interregional transactions.

The State of Washington seeks to improve the availability and reliability of its own electric generating resources and evaluate the development of generating resources to serve West Coast markets, all with a view to protecting other important state resources.

Development of a new, natural gas-fired, combined-cycle electric generating facility requires access to certain minimum requirements, including:

- Real property
- Natural gas
- Water
- Electric transmission lines
- Major equipment

After the developer has identified locations where these minimum requirements can be satisfied, the developer will weigh those locations against numerous other considerations in arriving at a decision about where best to site a new facility. Those considerations will include:

- State tax structure
- Cost of plant construction
- Cost of natural gas
- Cost of electric transmission
- Markets for electricity
- Timing and certainty of the site certification process
- Cost of environmental compliance

For the purposes of this study, we proposed development of a 520-megawatt, combined-cycle electric generating project fueled with natural gas and cooled with water (see Appendix A). We operated on the assumptions that prospective developers would place their emphasis on locating sites at which all necessary infrastructure requirements could be satisfied at the lowest achievable cost and at which there would be very few if any impediments to early development (see Appendix B). For instance, while some projects utilize oil as a backup fuel, we did not factor into our projections the cost of capital additions required for dual-fuel operations (ranging from $700,000 to $1,000,000 for tanks and other necessary apparatus to accommodate a 3-day supply, or approximately 2 million gallons, of backup fuel). Due largely to air quality compliance issues, oil is used as a backup fuel in facilities of this size only where natural gas availability is notably constrained or subject to frequent interruptions. Similarly, we did not factor into our projections the cost of air quality offsets in Oregon or Washington. Unlike California, both states have sites available that would not be subject to the requirement to obtain air quality offsets. And, we did not factor into our projections dry cooling as a substitute for water cooling (a design modification that may add considerably to project costs), because, given the option, developers would focus first on finding sites with adequate water resources.

We evaluated the cost of constructing and operating the project in Washington, Oregon and California. It was our objective to identify issues affecting project development in each of the three states under investigation.

Practical obstacles to the development of new, large-scale electric generating facilities in any of the three states under investigation include the reduced availability and increased cost of natural gas and the immediate shortage of electric generating equipment. Developers that are best equipped to proceed with new project construction are those that own or have otherwise tied up natural gas reserves and pipeline capacity and those that have placed advance orders for available generating equipment.

The installed cost of our typical project varies from state to state as a consequence of sales taxes and other state impositions. The installed cost of the project in the three states is as follows: Washington $386,860,000; Oregon $369,750,500; and California $386,100,000. Factors that add to the installed cost of the project in Washington include sales tax on the cost of project components and construction labor ($22,360,000) and permitting fees paid directly to the Energy Facility Site Evaluation Council ($500,000). Adding to the installed cost of the project in Oregon are a carbon dioxide mitigation fee ($5,500,000) and permitting fees paid directly to the

Energy Facility Siting Council ($250,000). And, adding to the installed cost of the project in California is the sales tax on the cost of project components and construction labor ($22,100,000).

Permitting fees paid directly to the respective siting authorities would normally be included in development costs where it would account for a negligible part of the total. For the purposes of this study, those fees have been broken out as a separate item to elucidate state-to-state differences. While the carbon dioxide mitigation fee assessed against projects in Oregon is shown as an addition to the project cost, air pollution offsets assessed in California are shown as an addition to annual operating expense.

Figure 1-1 depicts power plant construction costs for the three states under investigation.

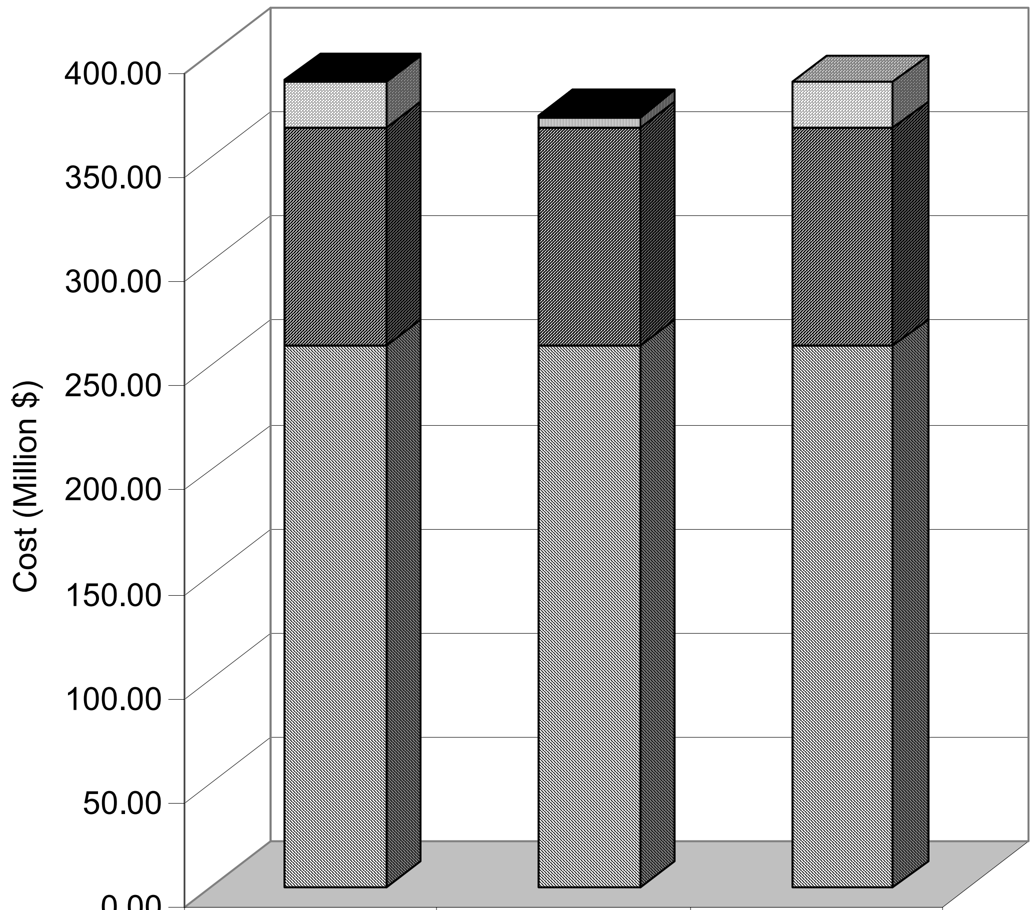
In addition to some variation in the cost of installation, the project would be subject to variations in annual operating expenses as a consequence of state impositions, including property taxes in each of the three states, sales tax on a portion of annual operation and maintenance ("O&M") expense in Washington and California (presumed to apply to ten percent of total O&M expense for the purposes of this study), brokered natural gas tax in Washington, corporate income tax in Oregon and California, and NO_x[1] offsets in California. Assuming our project operates at a 92% capacity factor, purchases gas at $4.00 per mmBtu, and sells all of its electric output at $60.00 per megawatt-hour, these annual impositions result in the cost additions shown in Table 1-1.

TABLE 1-1: ANNUAL OPERATING EXPENSE ADDITIONS RESULTING FROM STATE IMPOSITIONS

	Property	Sales Tax	Income Tax	Fuel Tax	NO_x Offsets	Total
Washington	**$3,896,568**	**$288,326**		**$4,390,869**		**$8,575,763**
Oregon	**$3,900,000**		**$4,459,896**			**$8,359,896**
California	**$3,385,200**	**$284,973**	**$5,857,034**		**$800,000**	**$10,327,207**

The effects of these impositions, taken together with other operating expenses and federal taxes, are shown in Figure 1-2.

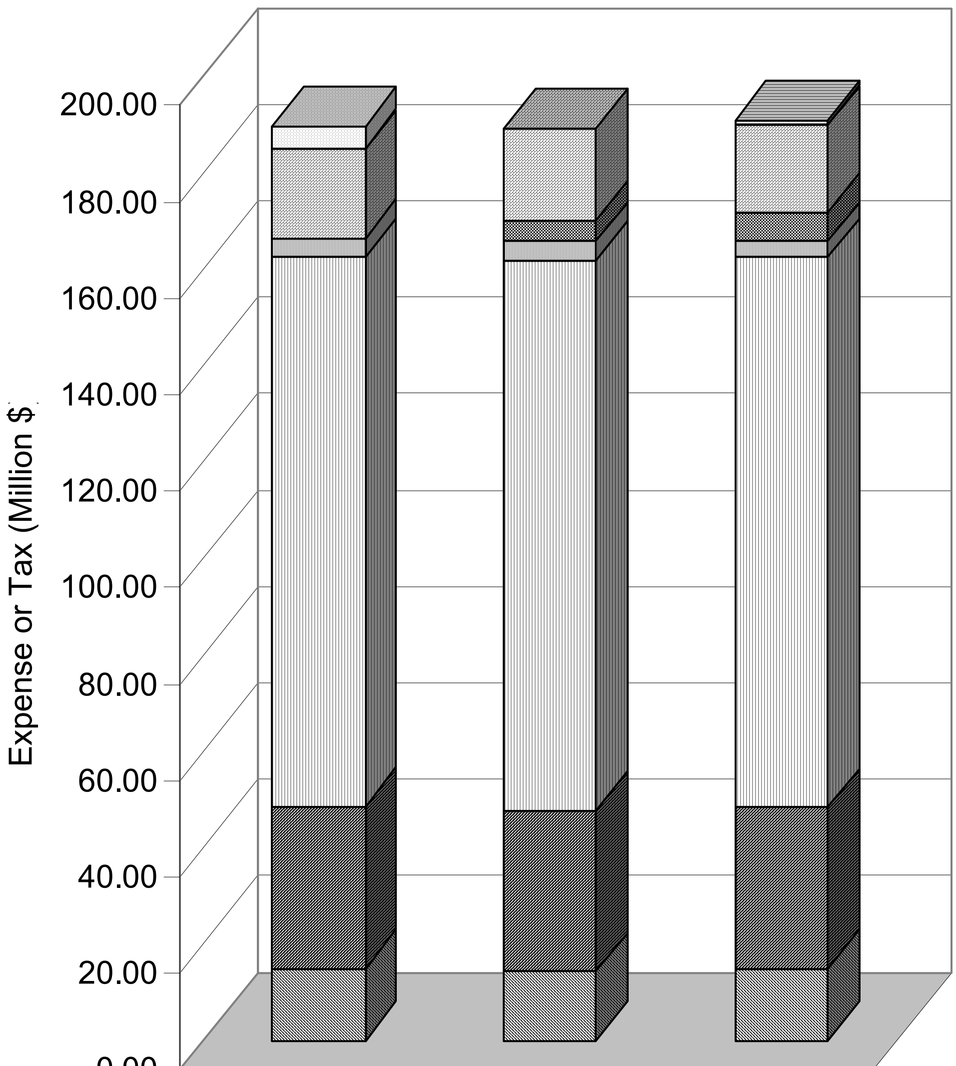
FIGURE 1-1: POWER PLANT CONSTRUCTION COST COMPARISON



	Washington	Oregon	California
Direct Permitting Costs	0.50	0.25	
CO2 Mitigation Fee		5.50	
State Sales Tax	22.36		22.10
Development Costs	104.00	104.00	104.00
EPC Costs	260.00	260.00	260.00

[1] PM_{10} offsets may be required in all states under investigation. SO_2 and HC offsets would be negligible compared to NO_x due to the low emissions from natural gas-fired plants.

FIGURE 1-2: POWER PLANT ANNUAL OPERATION EXPENSE & TAX COMPARISON



	Washington	Oregon	California
Air Quality Offsets			0.80
Fuel Tax	4.39		
State Sales Tax	0.29		0.28
Federal Income Tax	18.47	18.93	18.12
State Income Tax		4.46	5.86
Property Tax	3.90	3.90	3.39
Fuel Costs	113.99	113.99	113.99
O&M Costs	33.53	33.53	33.53
Debt Payment	14.94	14.28	14.91

Generally, over the life of the proposed project, the effects of local impositions favor Washington over both Oregon and California, particularly as the price of electricity increases (provided it does so in tandem with, or at a greater rate than, the price of natural gas).

We calculated the net present value ("NPV") of the typical electric generating project in each of the three states under investigation. While the NPV differs from state to state, even under the most dramatic set of assumptions the overall spread is less than ten percent. Washington, where project revenues are not subject to a state corporate income tax, rises to the top of the list as electricity prices escalate in tandem with, or at a greater rate than, natural gas prices.

Figures 1-3 and 1-4 illustrate the comparative NPV for the typical electric generating project sited in Washington, Oregon and California assuming a natural gas purchase price of $4.00 per mmBtu and assuming: (1) the project is 50-percent financed; and (2) the project is 100-percent financed. Similar results would be obtained using different natural gas pricing assumptions.

FIGURE 1-3: NPV COMPARISON FOR PROJECT WITH 50% FINANCING (GAS PRICE: $4/mmBtu)

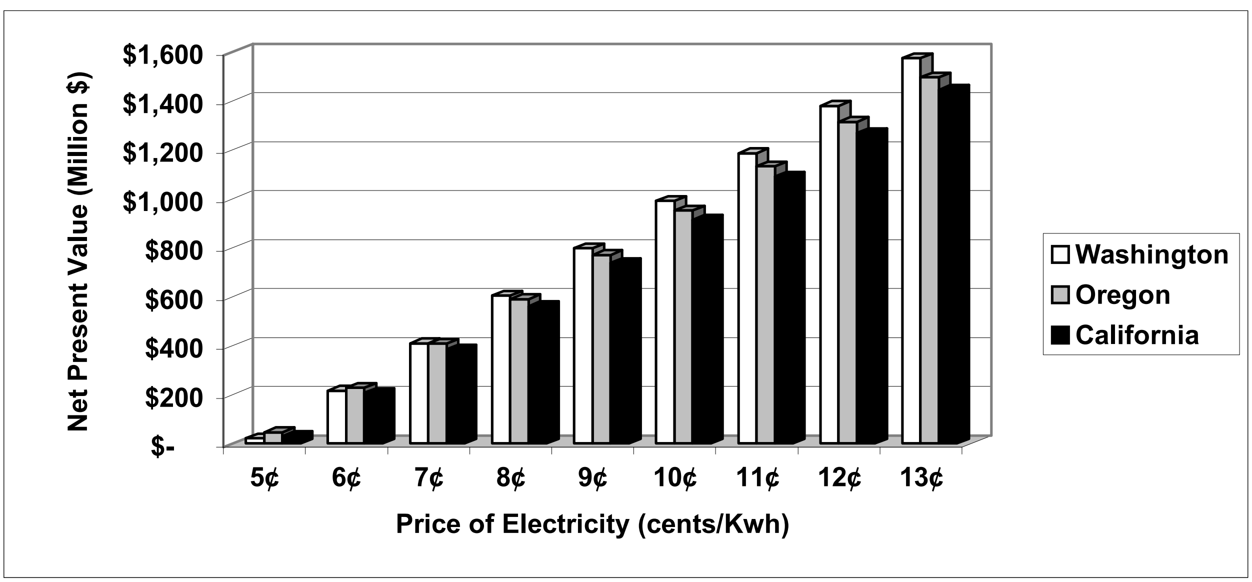
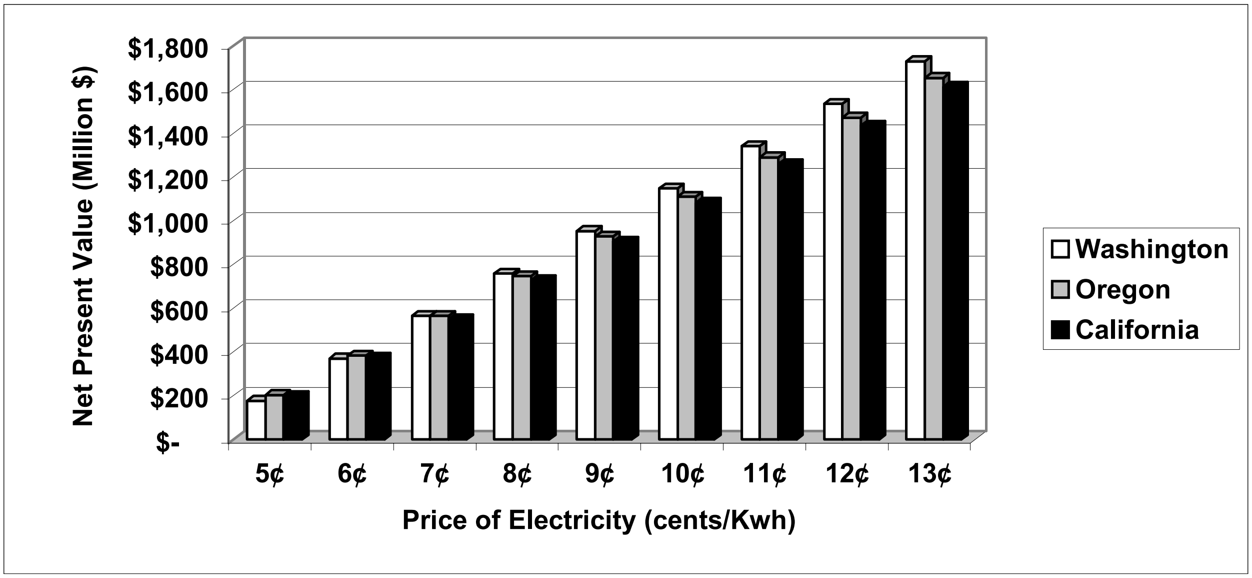


FIGURE 1-4: NPV COMPARISON FOR PROJECT WITH 100% FINANCING (GAS PRICE: $4/mmBtu)



The infrastructure necessary for plant development is available, to varying degrees, in each of the three states under investigation. In each state, there are locations with access to natural gas, water, and, with some limitations, electric transmission suitable for plant development. In California, to a greater extent than is true of Washington or Oregon, development may be hampered by water limitations, by land use issues, and by stringent air quality regulations.

Each of the three states under investigation offers a "one-stop" permitting process for large-scale electric generating projects. Centralizing the decision-making process for projects of this size and scope may expedite site certification. Still, permitting of our typical electric generating project would take approximately two years. Construction could take another two years. Developers clearly favor a permitting approach that is well defined, manageable, and cost-effective.

To a large extent, environmental standards are comparable in each of the states evaluated. However, in California, NO_x offsets may add approximately $0.20/MWh to the cost of generating electricity at foreseeable NO_x offset costs. During periods of price volatility, these costs may increase dramatically.

The financial community has been hesitant to fund merchant power plants, largely because the prospective developers are unable to demonstrate with any degree of certainty that their revenue streams will be sufficient to cover debt service and the establishment of expected reserves. Developers have been unable to make this showing because they have encountered difficulty in executing long-term contracts for the sale of output from their projects at acceptable prices. And, this predicament arises because the acceptable price for output from these facilities is higher than the retail price Northwest consumers have been accustomed to paying.

To the extent that debt financing is available, it is unlikely to account for more than 60-percent of the project cost. For this reason, developers with sufficient resources have turned to 100-percent commercial bond financing for their proposed projects. Other developers are exploring lease-financing arrangements. Developers with lesser resources may have great difficulty finding a source of project financing.

2. INTRODUCTION

Electric reserves have declined in the western United States. Several factors may contribute to this phenomenon, including low water conditions, salmon preservation efforts, transmission system limitations, population and industrial growth, lack of construction of new electric generating facilities, the decline of utility investments in energy efficiency and conservation, and the convergence of all of these factors with the onset of cold weather conditions and regularly scheduled plant maintenance.

Development of new sources of electric generation in Washington, Oregon and California has proceeded slowly in the recent past. In general, this slowness may be attributed to the low market price for electricity during the last ten years, coupled with uncertainty about the effects of ongoing or contemplated electric industry restructuring. Existing investor-owned electric utilities have avoided new investment in generation, pending decisions about how they will configure themselves in a restructured environment. Because of low market prices for electricity prior to 2000, many independent power producers have postponed development of new generating facilities costing hundreds of millions of dollars and often requiring a five-year development effort. During this period of uncertainty, the margin between supply and demand has narrowed.

Recognizing the importance of giving timely attention to these issues, the Energy Division, Office of Trade and Economic Development, State of Washington ("Energy Division"), seeks to understand the relative influence of Washington State's specific electric power plant siting requirements in comparison to Oregon and California and the effect of Washington's siting process on the decision to build new electricity generating facilities in Washington to serve state and West Coast markets.

The Energy Division engaged Pacific Energy Systems, Inc., to prepare an evaluation of the comparative electric power plant siting requirements in Washington, Oregon, and California focusing on:

- Environmental, Administrative and Other Legal Siting Requirements.
- Tax Obligations Related to Power Plant Construction and Operation.

- Other Issues Affecting the Decision to Size and Develop a Power Plant.
- Importance of Siting-Related Factors to the Financial Markets.

The report compares the siting environment in each of these three states, with emphasis on the environmental, permitting, tax and financing issues a prospective developer would confront in siting this facility in Washington, Oregon and California.

3. STATE-BY-STATE COMPARISON OF SITING REQUIREMENTS

Whether sited in Washington, Oregon or California, the typical large-scale electric generating project must satisfy applicable environmental, safety, and land use criteria. For the typical electric generating plant, these criteria are comparable in each of the three states under investigation. Their application, on the other hand, may militate against locating a facility in any one of the states. In many parts of California, for instance, the developer will find it especially difficult to satisfy air quality standards, to obtain necessary conditional land use approvals, and, in some instances, to obtain water sufficient for water-cooling. In urban Washington and Oregon, the developer may find it difficult to satisfy applicable air quality standards. And, in Oregon, the developer will be required to comply with a carbon dioxide mitigation standard that would add $5.5 million to the cost of the proposed project, based on project size and thermal efficiency.

Each state employs a "one-stop" permitting process for projects deemed to be of sufficient size to affect state interests, though each state sets a different size threshold. In all cases, this process makes provision for public input. In Oregon and Washington, a decision by the siting authority may be appealed directly to the State Supreme Court. In California, appeals would wind their way through normal administrative procedures.

The "one-stop" permitting process confers upon the lead agency authority to apply standards adopted by other state agencies. The lead agency places heavy reliance upon these other agencies for review of subject matter for which they possess special expertise. Only in rare instances will the lead agency override those standards in the public interest.

Washington Process. In Washington, authority to review and recommend approval or rejection of site certificate applications to the Governor for thermal electric generating projects with a rated capacity of 250 megawatts or more resides with the Energy Facility Site Evaluation Council (”EFSEC”). EFSEC consists of one representative from each of nine state agencies (Department of Ecology, Department of Fish and Wildlife, Department of Health, Military Department, Department of Community, Trade and Economic Development, Utilities and Transportation Commission, Department of Natural Resources, Department of Agriculture, and

Department of Transportation) and, during review of a specific application, one representative each from the county and city or port district in which the proposed project would be located.

The Washington process is typically initiated by an independently commissioned potential site study that identifies major environmental and other impacts associated with the proposed energy facility. This study is performed in consultation with state agencies, local governments, and other stakeholders. Following the completion of the potential site study, an applicant submits a site certificate application ("SCA"). The SCA must describe the project in detail, list all pertinent federal, state and local requirements, and address the elements set forth in Appendix C.

EFSEC employs an independent consultant to review the application to ensure it fully addresses the guidelines set forth in the Washington Administrative Code (WAC 463-42-135) and to begin preparation of the Environmental Impact Statement ("EIS") required under the State Environmental Policy Act ("SEPA"). Standards subject to review are shown in Appendix C. When the independent contractor has notified EFSEC that the application contains sufficient information for preparation of the EIS and commencement of adjudicative hearings, EFSEC proceeds to develop a draft environmental impact statement and then proceeds to an adjudicative phase with hearings. Once the application is determined to be complete, the 12-month statutory application review process begins.

An initial public hearing is scheduled in the vicinity of the proposed project within 60 days after receipt of the application for the purposes of informing the public about the proposed project and determining whether the project is consistent with local or regional land use plans. If the proposed project is not consistent with local land use plans, the applicant can apply to the local or regional land use authority for a variance. If the local or regional land use authority does not grant the variance, the applicant may request state preemption. In the event the applicant applies for state preemption, EFSEC holds an adjudicative hearing to take testimony regarding the request. EFSEC is charged with giving due consideration to community interests and local rules and ordinances in making any state preemption recommendation to the Governor.

A series of pre-hearing conferences may precede the scheduling of adjudicative hearings. These conferences allow for organizing and scheduling the hearings by subject area. Preparation of the draft EIS will ordinarily precede scheduling of the adjudicative hearings, though the final EIS will not be issued until the adjudicative hearings have been completed. Review of necessary air and water discharge permits is undertaken by EFSEC while the adjudicative hearings are underway. Additional hearings are held for the purpose of developing conditions that will attach to these permits. Generally, EFSEC observes Department of Ecology air and water quality standards in developing its recommendations. Permits ordinarily issued by the U. S. Environmental Protection Agency ("EPA") but delegated to EFSEC under state implementation provisions, e.g., the Prevention of Significant Deterioration air permit, may require concurrent signature/approval from the EPA.

If, upon completion of its review and adjudicative hearings, EFSEC determines it can recommend approval of the project, EFSEC develops a draft Site Certification Agreement ("SCA") for consideration by the Governor. Within 60 days after receipt of the draft SCA, the Governor may (1) approve EFSEC's recommendation and sign the SCA, (2) reject the application, or (3) direct EFSEC to reconsider some aspects of the project and draft SCA. If EFSEC determines it cannot recommend approval of the project, its final order explains its decision.

Historically, this entire process, from initiation of the potential site study to execution of the SCA, has taken approximately 18 to 24 months for a typical combustion turbine project. In addition to the costs incurred in conducting necessary environmental studies, plant engineering, and permit preparation (costs that may approach $2 million), the applicant is expected to reimburse EFSEC for staff time, consultants, and expenses, with costs ranging from $300,000 to $500,000. Participating agencies and other intervenors must fund their own participation in the application process.

Oregon Process. In Oregon, authority to review and approve site certificate applications for all electric generating projects producing 25 megawatts or more resides with the Energy Facility Siting Council ("EFSC"). Exempted from this process are qualifying high-efficiency cogeneration projects, i.e., projects that produce both electricity and thermal energy useful in an industrial process. EFSC consists of seven citizens appointed by the Governor.

The Oregon process is initiated when the applicant submits to the Oregon Office of Energy ("OOE") its Notice of Intent ("NOI"). The NOI must describe, in general terms, the proposed site, project, and possible impacts of development. It must describe proposed routes for linear facilities, including gas pipelines, water pipelines, and electric transmission lines. It must also contain a list of permits the applicant believes are applicable to the project, as well as a list of property owners affected by the project and its linear facilities. And, the NOI must indicate whether the applicant intends to demonstrate compliance with statewide land use planning goals by obtaining local land use approvals (Path A) or by obtaining an EFSC determination that the proposed project complies with the statewide land use planning goals (Path B).

OOE issues public notice of the NOI and holds at least one public information meeting in the vicinity of the proposed project. It also consults with all affected state agencies and local authorities to confirm that the NOI provides sufficient detail for each such agency and authority to identify how their requirements may be affected by the proposed project.

Within 140 days after receipt of the NOI, OOE issues a Project Order in which it identifies applicable statutes and rules and identifies any special information needed for the application. The Project Order also identifies the areas over which the applicant must assess the proposed project's potential impacts in detail (the "analysis areas").

After issuance of the Project Order, the applicant submits its Application for Site Certificate ("ASC") to OOE. The ASC must describe the project in detail and address the standards set forth in Appendix C.

OOE reviews the ASC and, upon determining it to be complete, considers the ASC to be filed. A final decision on the application is due within 9 months after the ASC is filed. Upon completion of its review of the filed ASC, OOE issues a draft proposed order containing determinations of compliance with applicable standards, as shown in Appendix C, and recommending conditions. OOE then schedules a public hearing to take notice of the concerns of any interested person.

The draft proposed order and public comments are made the subject of an initial review meeting held by EFSC (the "First Reading"). After the First Reading, OOE issues a proposed order and notice of contested case.

The contested case is held before an independent hearings officer and is open to the applicant and persons who have raised concerns in the public hearing and have been admitted as intervenors. At the conclusion of the contested case, the hearings officer provides a written order to EFSC. EFSC considers the written order and parties' exceptions to the order in deciding whether or not to issue a site certificate and what conditions the site certificate should contain. Any appeal of EFSC's final decision is directly and exclusively to the Oregon Supreme Court.

This entire process, from submission of the NOI to issuance of the site certificate, has generally taken from 22 to 29 months and may be expedited as warranted. In addition to the costs incurred in conducting necessary environmental studies, plant engineering, and permit preparation (costs that may approach $2 million), the applicant is expected to reimburse OOE for staff time, consultants, and expenses, at a cost approaching $250,000. In addition, Oregon applicants may expect to incur permit-related costs for offsetting carbon dioxide emissions, depending on plant size and thermal efficiency. For our proposed project, the cost of these offsets would be approximately $5.5 million.

California Process. In California, authority to review and approve site certificate applications for thermal electric generating projects producing 50 megawatts or more resides with the California Energy Commission (”CEC"). CEC consists of five members appointed by the Governor and representing specific areas of expertise: law, environment, economics, science/engineering, and the public at large.

The California process is initiated when the applicant submits to the CEC its Application for Certification ("AFC"). The AFC must describe the project in detail and address the standards set forth in Appendix C.

The CEC staff reviews the AFC for completeness, placing heavy reliance upon state agencies possessing requisite expertise. Within 30 days after filing of the AFC, the CEC staff must make a data adequacy recommendation to the CEC. The CEC must act upon that recommendation within 45 days after filing of the AFC. If the AFC is found to be incomplete, the CEC provides the applicant with a written list of deficiencies to be addressed by the applicant in a supplemental filing. The CEC must make any subsequent data adequacy determination within 30 days after receipt of the supplemental filing.

When the AFC is found to be complete, the CEC staff collects additional data from the applicant and other agencies for impact analysis. Public workshops on technical and procedural matters and informational hearings are held during this phase.

The CEC staff conducts an independent analysis, focusing on a thorough examination of environmental impacts, mitigation measures, and development of a compliance plan. As a result of this analysis, the staff prepares a Preliminary Staff Assessment. Public workshops are held for discussion of the Preliminary Staff Assessment. Thereafter, the staff prepares a Final Staff Assessment that serves as the staff's testimony during the hearing phase.

Public hearings are then held before an Energy Commission Committee (two members of the CEC). Interested parties and the public can testify or provide comments at these hearings. The Energy Commission Committee prepares the Presiding Member's Proposed Decision that is released for public review and comment after the close of hearings. The Presiding Member's Proposed Decision, together with any revisions resulting from public review and comment, is heard by the full Commission and either adopted, modified or rejected. Depending on that decision, the AFC is either approved by the full Commission with conditions or denied. Any appeal of that decision is to the court of appeal or the California Supreme Court.

In California, the review and approval process is to be completed within 12 months after the application is found data adequate. As with Washington and Oregon, the entire process, from submission of the Application for Certification to approval of the AFC, is likely to take two years or more. To strengthen the proposition that its rulings are fair and objective, the CEC does not charge fees for processing an AFC. The applicant may be expected to bear some costs associated with other permits related to the facility, and these costs are included under the project development costs applicable to the proposed project in all three of the states under investigation.

Notably, recognizing that California faced potentially serious electricity shortages in the near future, the California Legislature passed the California Energy Security and Reliability Act of 2000 on August 31, 2000. As a consequence of that Act, the CEC instituted a 6-month licensing process for thermal power plants. To be eligible for this expedited process, the proposed project must qualify for a negative declaration as defined by the California Environmental Quality Act. The proposed project must also satisfy the following conditions:

- Meets or exceeds all local, state, and federal air quality rules, including Best Available Control Technology requirements, and has contracts for all required air emission offsets.
- Does not cause adverse water impacts or does not require new appropriations of water.
- Is in full compliance with all land use requirements, including General Plans and zoning requirements.
- Avoids significant natural resources, including rare, threatened, and endangered species.
- Avoids significant adverse impacts and electricity system reliability problems.

Because the expected electricity shortages became a reality for California in late 2000 and early 2001, further efforts are being made to expedite the plant siting process, particularly for projects in the 50-megawatt to 100-megawatt range.

TABLE 3-1: STATE-BY-STATE COMPARISON OF SITING ISSUES

	Washington	Oregon	California
Siting Authority	EFSEC	EFSC	CEC
SEPA or CEQA Authority	EFSEC	-----	CEC
Air Quality Authority	EFSEC	DEQ	CEC
Water Quality Authority	EFSEC	DEQ	CEC
Site Certificate Fees	$300,000 – 500,000	$250,000	-----
Statutory Permitting Time	12 months after finding of completeness	9 months after finding of completeness	12 months after finding of completeness
Average Permitting Time	18 to 24 months	22 to 29 months	24 months
Appeals	State Supreme Court	State Supreme Court	Normal Administrative Procedures

4. TAX OBLIGATIONS FOR TYPICAL POWER PLANTS

For the purposes of projecting annual taxes applicable to the typical power plant, it is necessary to make certain assumptions about the cost of natural gas and the price of electricity. The analysis that follows is based upon the assumptions shown in Appendix E: Baseline Assumptions for Typical Power Plant with 50% Financing and Appendix F: Baseline Assumptions for Typical Power Plant with 100% Financing. Sensitivity to gas and electricity prices of the assumptions regarding net present value for Washington projects is reflected in Appendix G: Sensitivity of Washington Power Plant NPV (50% Financing) and Appendix H: Sensitivity of Washington Power Plant NPV (100% Financing).

TABLE 4-1: STATE TAXES APPLICABLE TO ELECTRIC POWER PLANTS

	Washington	Oregon	California
State Sales Tax	6.50 %	None	4.75 %
Local Sales Tax	0 – 2.10 %	None	2.25 – 3.75 %
Corporate Income Tax	None	6.60 %	8.84 %
Property Tax[2]	1.38 %	1.50 %	1.20 %
Public Utility Tax[3]	3.873 %	None	None
Natural Gas Tax	3.852 %	None	None

Washington Taxes. In Washington, the developer would be required to pay sales tax at the rate of 6.5 to 8.6% on the constructed cost of the generating plant, depending upon project location and the corresponding local sales and use tax. If the constructed cost of the plant were $260 million ($500/MW), excluding permitting, financing, and other development costs, the applicable sales tax would range from $16.9 million to $22.7 million, for a total after-tax cost of at least $277 million. Permitting, financing and other project development costs would add $104

[2] State property tax may vary depending on voter-approved local assessments.

million ($200/MW) to the cost of the project. The direct cost of completing the site certification process, i.e., fees payable to EFSEC to compensate the agency for the independent consultant's services, staff time, and associated expenses, would be approximately $500,000. Total installation cost of the generating plant would be at least $386.9 million.[4]

In addition, the developer would be required to pay annual property tax at the rate of approximately 1.38% on the assessed value of the generating plant, sales tax on a portion of its operating and maintenance ("O&M") costs, and natural gas tax at the rate of 3.852% on the cost of natural gas consumed by the project. Assuming the assessed value of the project is $277 million (constructed cost, not including permitting, financing and other development costs, plus applicable sales tax), the property tax payable annually would be $3.82 million (though this assessment would be expected to decline over time due to plant depreciation). Assuming sales tax is chargeable to ten percent of O&M costs, the sales tax payable annually would be $217.921. Assuming fuel costs are $114 million (at $4.00/mmBtu), the natural gas tax would be $4.39 million. Naturally, this number would rise and fall in concert with natural gas prices.

As a merchant plant, the project would be unlikely to realize any impact from the Washington Public Utility Tax ("PUT"). Because, by definition, the project would be a light and power business, it would be subject to PUT. That tax applies to gross receipts from sales of electricity at the rate of 3.873%. Allowable deductions from gross receipts include, among others: (1) sales of electricity for resale inside or outside Washington; and (2) sales of electricity for consumption outside Washington. Most projects would qualify for one or the other of these deductions and would be very unlikely to pay this tax.

First year Washington tax obligations for the typical project would be $8.58 million, including property tax of $3,896,568, sales tax of $288,326, and brokered natural gas tax of $4,390,869.

[3] The Washington Public Utility Tax applies to gross receipts realized by all light and power businesses. However, because sales for resale, inside or outside Washington, or sales for consumption outside Washington are deducted from gross receipts before computing the tax, most developers would be unaffected by this tax.
[4] In the event Washington imposes a carbon dioxide emissions mitigation requirement substantially similar to the Oregon requirement, the total installation cost could increase by an additional $5.5 million, depending on plant capacity and thermal efficiency.

The net present value of the after-tax profit on the typical project in Washington, assuming 50-percent debt financing, a purchased gas price of $4.00/mmBtu, and an electricity sales price of $60.00/MWh, would be $216.42 million. (See Appendix D.)

Oregon Taxes. In Oregon, no sales tax would apply to the constructed cost of the generating plant. Permitting, financing and other project development costs would add $104 million to the cost of the project. The direct cost of completing the site certification process, i.e., fees payable to the Oregon Office of Energy, would be $250,000. Addition of the Oregon carbon dioxide mitigation fee would cause the project cost to increase by an additional $5.5 million. Total installation cost of the generating plant would be $369.8 million, as shown in Appendix D.

In addition, the developer would be required to pay annual property tax at the rate of at least 1.5% (excluding voter-approved local assessments) on the assessed value of the generating plant and annual income tax at the rate of 6.6% on taxable revenue. Assuming the assessed value of the plant is $260 million, excluding permitting, financing, and other development costs, the annual property tax would be at least $3.9 million. Assuming annual taxable income is $67.57 million, the applicable state income tax would be $4.46 million.

Annual Oregon tax obligations for the typical project would be $8.36 million.

The net present value of the after-tax profit on the typical project in Oregon, assuming 50-percent debt financing, a purchased gas price of $4.00/mmBtu, and an electricity sales price of $60.00/MWh, would be $227.73 million. (See Appendix D.)

California Taxes. In California, the developer would be required to pay sales tax at the rate of approximately 8.5% on the constructed cost of the generating plant. If the constructed cost of the plant were $260 million, excluding permitting, financing, and other development costs, the applicable sales tax would approximate $22.1 million, for a total after-tax cost of $282.1 million. Permitting, financing and other project development costs would add $104 million to the cost of the project. Total installation cost of the generating plant would approach $386.1 million.

The developer would also be required to pay annual property tax at the rate of at least 1.20% on the assessed value of the generating plant, sales tax on a portion of its operating and maintenance ("O&M") costs, and annual income tax at the rate of 8.84% on taxable revenue. Assuming the assessed value of the plant is $282.1 million, excluding permitting, financing, and other development costs, the annual property tax would be at least $3.39 million. Assuming sales tax is chargeable to ten percent of O&M costs, the sales tax payable annually would be $284,973. Assuming annual taxable revenue is $66.26 million, the applicable state income tax would be $5.86 million.

Annual California tax obligations for the typical project would be in the amount of $9.54 million.

The net present value of the after-tax profit on the typical project in California, assuming 50-percent debt financing, a purchased gas price of $4.00/mmBtu, and an electricity sales price of $60.00/MWh, would be $207.75 million. (See Appendix D.)

Comparative Tax Effects. Despite the very different taxing mechanisms in the three states under investigation, the comparison of tax effects on the typical electric generating plant reveals there is relatively little difference between Washington, Oregon and California on a net present value basis. Recognizing this evaluation is based on a host of assumptions that may be subject to further verification, net present value of after-tax profit in Washington is $216.42 million, in Oregon is $227.73 million, and in California is $207.75 million. If the price of electricity were to increase in tandem with or at a greater rate than the cost of natural gas, Washington would become the favored state because the generating plant would realize improved net profit in a state that does not impose a corporate income tax on profits from the operation. If the price of natural gas increases at a greater rate than the price of electricity, Washington's position declines. Table 4-2 is intended to show the sensitivity to natural gas and electricity prices of NPV in the three states under investigation. (See Appendices G through L for additional examples.)

TABLE 4-2: SENSITIVITY OF 50%-FINANCED PLANT NPV TO ELECTRICITY & GAS PRICES

	Washington	Oregon	California
Natural Gas Price: $3/mmBtu			
Electricity Price: $60/MWh	$353,000,000	$351,000,000	$328,000,000
Electricity Price: $100/MWh	$1,130,000,000	$1,076,000,000	$1,036,000,000
Natural Gas Price: $4/mmBtu			
Electricity Price: $60/MWh	$216,000,000	$228,000,000	$208,000,000
Electricity Price: $100/MWh	$993,000,000	$953,000,000	$916,000,000
Natural Gas Price: $5/mmBtu			
Electricity Price: $60/MWh	$79,000,000	$104,000,000	$87,000,000
Electricity Price: $100/MWh	$856,000,000	$830,000,000	$795,000,000

Developers interviewed in the course of this investigation were quick to point out that taxes do not weigh heavily in their decisions about where to site a new generating project. Of far greater importance are infrastructure, availability of natural gas and major equipment, reliability of the permitting process, and availability of financing alternatives.

5. FINANCIAL MARKET ISSUES AFFECTING POWER PLANT SITING

The financial markets are reluctant to lend funds for the development of merchant power plants. Unlike lending to the regulated utilities that were "guaranteed" a return on their investment as a consequence of including the generating facility in their rate base, the merchant plants often have few if any certain sales. And, unlike the independent power projects developed pursuant to the Public Utility Policies Act of 1978 ("PURPA"), the electric output from which the regulated utilities were required to buy, the merchant plants often have no fixed rate contracts for sale of their output. Clearly, the merchant plant with firm contracts for the sale of some acceptable percentage of its output will fare better in the financial markets than the merchant plant relying solely on the spot market.

Of greatest concern to the financial markets is the projected revenue stream expected to flow from operation of the proposed electric generating facility. That revenue stream must be sufficient to cover debt service plus some predetermined reserve margin. The prospective lender will cause the developer's revenue projections to be verified by an independent analyst. To the extent the developer has firm contracts for the purchase of gas and the sale of electricity, these projections will be more easily verified. In addition, lenders have placed increasing emphasis on the project's debt coverage ratio and are unlikely to loan amounts in excess of sixty percent of the project's total installation cost.

In determining whether to put their funds at risk, in addition to limiting the amount of debt a project may incur and demanding detailed showings of the project's expected revenue stream, the financial markets will conduct detailed studies of the proposed project, the borrower's track record, and all contracts bearing upon the success of the project. Issues of particular importance in making a funding decision include the following:

- Verify that all necessary permits have been obtained or will be obtained as required.
- Ensure that permits contain no "regulatory outs", i.e., provisions enabling the regulatory authority to suspend or revoke the permits based on conditions over which the applicant has little or no control.

- Conduct detailed engineering evaluation to ensure the project will meet the developer's expectations.
- Verify property ownership.
- Verify fuel procurement agreements.
- Verify water procurement agreements.
- Verify electric sales agreements.
- Require corporate guarantee from responsible parent with acceptable financial statements.

The availability of debt financing in current markets may be limited to those developers who can demonstrate they have firm contracts for the sale of all or a substantial portion of the project output. Uncertainty about the final outcome of industry restructuring has created obstacles to the execution of such contracts. Even with such contracts in hand, debt financing may be available for only 50% to 60% of project costs.

Some independent power producers interested in positioning themselves to take advantage of lucrative spot market opportunities and undaunted by the unwillingness of prospective consumers to enter into long-term, fixed-price contracts, have gone to the commercial bond markets where they have been successful in obtaining 100-percent financing for their proposed projects. This method of financing may be available only to very well recognized developers with excellent financial credentials.

6. KEY DISTINCTIONS BETWEEN THE STATES

Environmental standards that apply to construction and operation of our typical electric generating plant are comparable in the three states under investigation. Application of those standards is most severe in California where air quality is of paramount importance. The tax structure and the permitting processes differ from state to state.

In Washington, permitting the typical electric generating plant could take, on average, 18 months at a direct cost, excluding environmental studies, plant engineering, permit preparation, and other related costs, approaching $500,000. The Washington state sales tax would add approximately $22.4 million to the constructed cost of the plant. Total plant cost additions in Washington would be approximately $22.9.

Annual property taxes would be approximately $3.9 million; sales taxes would be approximately $288,326; and natural gas taxes would be approximately $4.39 million. Total annual tax impacts in Washington would be approximately $8.58 million. The net present value of the after-tax profit on the typical project in Washington, assuming 50-percent debt financing, a gas purchase price of $4.00/mmBtu and an electricity sales price of $60.00/MWh, would be $216.42 million.

In Oregon, permitting could take from 22 to 29 months (though much effort is being expended to expedite the process) at a direct cost of approximately $250,000. If the project involved federal action requiring the preparation of an environmental impact statement, the cost of that effort would also be borne by the applicant. No sales tax would apply to the constructed cost of the project. Application of the carbon dioxide standard would add approximately $5.5 million to the constructed cost of the plant. Total plant cost additions in Oregon would be approximately $5.75 million.

Annual property taxes would be approximately $3.9 million, and annual corporate income taxes would be approximately $4.46 million. Total annual tax impacts would be approximately $8.36 million. The net present value of the after-tax profit on the typical project in Oregon, assuming

50-percent debt financing, a gas purchase price of $4.00/mmBtu and an electricity sales price of $60.00/MWh, would be $227.73 million.

In California, permitting would take approximately 24 months (6 months if the applicant qualified for the expedited process) at no direct cost to the applicant. The California state sales tax would add approximately $22.1 million to the constructed cost of the plant. Total plant cost additions would be approximately $22.1 million.

Annual property taxes would be approximately $3.39 million; sales taxes would be approximately $284,973; corporate income taxes would be approximately $5.86 million, and the cost of NO_x offsets would be approximately $800,000 (though this amount may be subject to wide variations, depending upon the volatility of the offsets markets). Total annual tax impacts would be approximately $9.53 million, and air quality offsets would add $800,000 to annual costs. The net present value of the after-tax profit on the typical project in California, assuming 50-percent debt financing, a gas purchase price of $4.00/mmBtu and an electricity sales price of $60.00/MWh, would be $207.75 million.

On a net present value basis, the project fares best in Oregon ($227.73 million), second best in Washington ($216.42 million), and third best in California ($207.75 million). However, the difference between the three states is relatively small, particularly given the very generalized assumptions incorporated in the evaluation. It should be noted that the cost of natural gas could quickly overwhelm any small difference in impositions from state to state. It should also be noted that the relative positions of Washington and Oregon change quickly as the price of electricity increases in tandem with, or at a greater rate than, the cost of natural gas.

Factors considered important by developers include: availability of infrastructure, availability of major equipment, gas supply, water supply, markets for electricity (particularly long-term, fixed-price contracts for the sale of project output), reliability of the permitting process, and availability of project financing.

In all of the states under investigation, the permitting process takes about two years. It should also be noted that the developer could spend up to $2 million, in addition to permit fees collected in Oregon and Washington, in moving the process to the point of site certification. The developer, while recognizing the need to respond to applicable standards, seeks some certainty that the process is well defined and the outcome is predictable.

7. APPENDICES

APPENDIX A: TYPICAL ELECTRIC POWER PLANT PARAMETERS

Configuration.	Two 175-megawatt gas turbines, one 180-megawatt steam turbine		
Capacity Factor.	92 percent		
Electric Output.	Gross plant output - 530 megawatts		
	Plant load - 10 megawatts		
	Net plant output - 520 megawatts.		
Capital Cost.	Engineering, Procurement & Construction	\$260 million	(\$500/KW)
	Development, Permitting, Financing, etc.	\$104 million	(\$200/KW)
	Total Cost	\$364 million	(\$700/KW)
Fuel Consumption.	3,604 mmBtu/hr (6800 Btu/kWh HHV)		
Water Consumption.	3000 gallons per minute; 1.58 billion gallons per year		
Emissions.	NO_x (2.5 ppm)	31 lb/hr 135 tons/year	
	CO (4.0 ppm)	30 lb/hr 131 tons/year	
	PM10	38 lb/hr 166 tons/year	
	VOC	7.2 lb/hr 32 tons/year	

APPENDIX B: TYPICAL POWER PLANT & NECESSARY INFRASTRUCTURE

The typical natural gas-fired electric generating plant and its associated facilities must be sited near necessary infrastructure, including natural gas pipelines, a source of water for steam production and cooling, and electric transmission for moving electricity to the load centers. Developers will seek out sites in close proximity to the necessary infrastructure and then evaluate those sites against other criteria that may argue for or against development.

Power Plant. For the purposes of this analysis, a typical electric power plant will be a net 520-megawatt combined cycle, natural gas-fired facility. That facility is described in greater detail in Appendix A: Typical Electric Power Plant Parameters.

Necessary Infrastructure. Operation of the typical power plant will require access to natural gas, water, electric transmission, and wastewater disposal facilities. Identification of prospective project sites is accomplished through the use of a site selection process designed to measure accessibility of these key components and all other necessary facilities. A typical site selection process would evaluate the following features at any prospective power plant site:

1. **Access to Natural Gas and Natural Gas Pipelines.** Operation of the power plant will require continuous consumption of very large quantities of natural gas (3536 million Btu per hour; 28,497,331 million Btu per year at 92% capacity factor). Short interruptions in the supply of natural gas could be accommodated by the use of diesel fuel if its use is authorized under the applicable air quality permit and if the developer chooses to invest in backup fuel supply facilities and maintain an onsite inventory of fuel oil. The plant must have access to a supply of natural gas and one or more natural gas transmission lines. Key issues include:
   - Natural gas supply
   - Natural gas transmission pipeline
   - Distance to pipeline
   - Pipeline size and pressure (maximum/minimum)
   - Pipeline maximum capacity and available capacity
   - Expansion Plans/Subscription Schedule

2. **Access to Electric Transmission Lines.** Marketing output from the power plant will require access to electric transmission lines. Key issues include:
   - Owner of transmission line
   - Distance to transmission line
   - Accessibility of substations and interconnection points
   - Transmission line rating (generally 115, 230 or 500kV)

- Transmission line maximum capacity and available capacity
- Expansion plans
- Wheeling rates
- Cost of system upgrades

3. **Access to Water.** Operation of a water-cooled combined-cycle power plant will require continuous consumption of large quantities of water (180,000 gallons per hour; 1.45 billion gallons per year at 92% capacity factor) required for steam production and cooling. Where water supplies are limited, e.g., eastern Oregon and Washington and much of California, air-cooled condensation may be utilized at a capital cost addition of approximately $20 million (an amount that may be partially offset by elimination of the need for a water supply pipeline and cooling tower and by reduction of annual water expenses). If equipped with air-cooled condensers, the amount of water required for operation of the power plant will be reduced by 90% to approximately 18,000 gallons per hour, or 145 million gallons per year (and electric output would be reduced on hot days). Key issues include:

- Source of water
- Availability of water rights
- Water quality
- Distance to water source
- Process water pipeline size and capacity

4. **Means of Wastewater Disposal.** Most water used for steam production and cooling will evaporate. The water that remains may contain high concentrations of dissolved solids (salts). Key issues include:

- Potential treatment facilities and receiving bodies
- Operating Agencies

5. **Markets for Electricity.** Until recently, most electric generating plants were built by the vertically-integrated, regulated electric utilities as the need for new generation was stimulated by an increase in customer demand. The principal exceptions to this rule were: (1) power plants built by energy-intensive industries to satisfy their own, on-site requirements, and (2) power plants ("qualifying facilities") built by independent developers because, pursuant to the Public Utility Regulatory Policies Act of 1978 ("PURPA"), the regulated electric utilities were obligated to purchase their output.

   Since enactment of the Energy Policy Act of 1992, new generating plants are more likely to be developed by independent power producers, though some utilities may continue to generate their own electricity, including constructing and operating new plants, and some end-users may develop on-site generation to satisfy their own requirements (perhaps with a view to selling any excess capacity). The independent power projects will sell their output to the regulated utilities, the power brokers and marketers, and, where industry restructuring has allowed for direct access, directly to the end-user.

Accordingly, access to markets is a very important consideration for the project developer. Key markets include:

- Local utilities, including investor-owned utilities, public utility districts, municipal utilities, and cooperatives
- Local industries
- Trading hubs

6. **Property Rights.** The project developer must acquire property rights sufficient for development of the project and all related and supporting facilities. Key issues include:
   - Land Use/Zoning
   - Availability
   - Cost

7. **Government Issues.** Each prospective site must be considered in light of state, regional, local, or special district government issues affecting its potential for development. Such issues may include rates of taxation and special economic incentives, e.g., economic development zones favoring industrial development.

8. **Permitting and Regulatory Issues.** Each prospective must be considered in light of federal, state and local permitting and regulatory issues affecting development. Key issues include:
   - Time required for obtaining necessary permits
   - Certainty of the permitting process
   - Cost associated with permit preparation and approval
   - Cost of ongoing regulatory compliance

9. **Environmental Issues.** Each prospective site must be evaluated in light of prospects for satisfactorily addressing applicable environmental laws and regulations. Key issues include:
   - Local air quality standards
   - Wastewater discharge
   - Visual aesthetics
   - Archaeological and cultural sensitivities
   - Threatened or endangered species
   - Wildlife habitat
   - Environmentally sensitive areas
   - Geology
   - Socio-Economic Issues

10. **Cogeneration Potential.** Sites situated on or adjacent to industrial users of both thermal energy and electricity may be particularly attractive to prospective developers. The industrial user may serve as both a host for the energy facility and a consumer of all or a portion of its output. To the extent that the use of steam or other thermal energy produced by the facility contributes to more efficient energy utilization, the proposed facility may qualify for special incentives. For instance, in Oregon such a facility may qualify as a high-efficiency cogeneration project exempt from EFSC jurisdiction and may be eligible for energy tax credits and financing under the Small Energy Loan Program. Or, again in Oregon, it may offset the carbon dioxide emissions that would otherwise add to the cost of the facility.

APPENDIX C: SITING STANDARDS & RESPONSIBLE AGENCIES

	Washington Thermal Energy Facility 250 MW or more	**Oregon** Thermal Energy Facility 25 MW or more	**California** Thermal Energy Facility 50 MW or more
SEPA or CEQA	EFSEC	-----	CEC
Managerial and Technical Expertise	-----	EFSC	CEC
Air Pollution Prevention and Control	EFSEC	DEQ	CEC
Water Pollution Prevention and Control	EFSEC	DEQ	CEC
Land Use	EFSEC	EFSC or local land use authority (at option of Applicant	CEC
Water Resources	EFSEC	EFSC	CEC
Geology	EFSEC	EFSC	CEC
Soil Conditions	EFSEC	EFSC	CEC
Wetlands	EFSEC	EFSC	CEC
Protected Areas	EFSEC	EFSC	CEC
Fish and Wildlife	EFSEC	EFSC	CEC
Threatened and Endangered Species	EFSEC	EFSC	CEC
Aesthetics	EFSEC	EFSC	CEC
Visual Impacts (Light and Glare)	EFSEC	EFSC	CEC
Historic and Cultural Resources	EFSEC	EFSC	CEC
Recreational Facilities	EFSEC	EFSC	CEC
Socio-Economic Impacts	EFSEC	EFSC	CEC
Waste Minimization	-----	EFSC	-----
Noise	EFSEC	EFSC	CEC
Facility Retirement	EFSEC	EFSC	CEC
Agricultural Crops and Animals	EFSEC	-----	-----
Carbon Dioxide Mitigation	-----	EFSC	-----
Air Quality Offsets	-----	-----	Air Quality Management District

APPENDIX D: EFFECT OF STATE IMPOSITIONS ON ECONOMIC RETURN

[Assumptions: 50% Debt Financing; Gas Price: $4/mmBtu; Electricity Price: $60/MWh]

	Baseline Values	Washington	Oregon	California
Baseline EPC Cost	$ 260,000,000			
State and Local Sales Tax Rate (1)		8.60%	0.00%	8.50%
State Sales Tax ($)		$ 22,360,000		$ 22,100,000
Baseline Development Costs	$ 104,000,000			
Carbon Dioxide Mitigation Fee			$ 5,500,000	
Direct Permitting Cost		$ 500,000	$ 250,000	
Total Installation Cost	$ 364,000,000	$ 386,860,000	$ 369,750,000	$ 386,100,000
Debt (% of Total Installation Cost)	50%	50%	50%	50%
Annual Debt Payment (2) ($/year)	$ 14,056,581	$ 14,939,365	$ 14,278,628	$ 14,910,016
Baseline O&M Cost ($/year)	$ 33,526,272			
Emission Mitigation Costs ($/year)				$ 800,000
State Sales Tax on O&M (1) (3) ($/year)		$ 288,326		$ 284,973
Total Annual O&M Cost ($/year)	$ 33,526,272	$ 33,814,598	$ 33,526,272	$ 34,611,245
Baseline Fuel Cost ($/year)	$ 113,989,325			
Fuel Tax Rate		3.852%	0.000%	0.000%
Fuel Taxes ($/year)		$ 4,390,869		
Total Annual Fuel Cost ($/year)	$ 113,989,325	$ 118,380,194	$ 113,989,325	$ 113,989,325
Property Tax Rate (4)		1.38%	1.50%	1.20%
Property Tax Payment ($/year) (5)		$ 3,896,568	$ 3,900,000	$ 3,385,200
Cost of Electricity Production ($/year)	$ 161,572,177	$ 171,030,724	$ 165,694,225	$ 166,895,786
Gross Revenue	$ 251,447,040	$ 251,447,040	$ 251,447,040	$ 251,447,040
Pre-Tax Profit ($/year)	$ 89,874,863	$ 80,416,316	$ 85,752,815	$ 84,551,254
State Taxable Income (6)	$ 75,818,282	$ 61,580,383	$ 67,574,187	$ 66,256,038
State Income Tax Rate		0.00%	6.60%	8.84%
State Income Tax ($/year)			$ 4,459,896	$ 5,857,034
Federal Taxable Income (7)	$ 75,818,282	$ 61,580,383	$ 63,114,290	$ 60,399,004
Federal Income Tax Rate	30%	30%	30%	30%
Federal Income Tax ($/year)	$ 22,745,485	$ 18,474,115	$ 18,934,287	$ 18,119,701
After Tax Profit ($/year)	$ 67,129,378	$ 61,942,201	$ 62,358,632	$ 60,574,519
Equity Contribution to Installation	$ 182,000,000	$ 193,430,000	$ 184,875,000	$ 193,050,000
NPV of After Tax Profit (million $) (8)	$ 262.2	$ 216.42	$ 227.73	$ 207.75
Variation of NPV from State of Washington NPV		0.00%	5.23%	-4.01%

(1) Assumes maximum local sales tax rate. Some jurisdictions may have lower rates.
(2) The annual debt payment is an approximation of the average interest and depreciation deducted from gross profit to determine state and federal taxable income. In early years, the deduction would be greater than the capital payment; in later years, it would be less than the capital payment.
(3) Sales tax is assumed to be chargeable to 10 percent of baseline O&M costs.
(4) Property tax rate includes 0.2% local assessments in California.
The property tax rate in Oregon varies substantially between jurisdictions. The given value is typical.
(5) Assessed value of power plant is taken to be equal to the baseline EPC cost plus sales tax on the EPC cost.
(6) State taxable Income equals pre-tax profit minus annual capital payments and property tax.
(7) Federal taxable income equals pre-tax profit minus capital payments, property tax, and state income tax.
(8) NPV is the NPV of after tax profits minus the initial equity contribution in year zero.

APPENDIX E: BASELINE ASSUMPTIONS FOR TYPICAL POWER PLANT WITH 50% FINANCING

Plant Output	
Plant Capacity (MW)	**520**
Capacity Factor	**92%**
Annual Generation (MWh/yr)	4,190,784
Installation Costs	
Engineering, Procurement, and Construction Cost ($/kW)	**500**
Engineering, Procurement, and Construction Cost ($)	$ 260,000,000
Development Costs ($/kW) (1)	**200**
Development Costs ($) (1)	$ 104,000,000
Baseline Installation Cost ($/kW)	$ 700
Baseline Installation Cost ($)	$ 364,000,000
Financing Costs	
Debt (% of Installation Cost)	**50%**
Debt	$ 182,000,000
Equity	$ 182,000,000
Interest Rate	**7.0%**
Term (yr)	**35**
Capital Recovery Factor for Debt Payment	7.72%
Annual Debt Payment ($)	$ 14,056,581
Unit Cost of Debt ($/MWh)	$ 3.4
Owner's Discount Rate	**15.0%**
Project Life (years)	**35**
Capital Recovery Factor for NPV Calculation	15.11%
Operation and Maintenance Costs	
Unit Cost of O & M ($/MWh)	**$ 8.0**
Annual O&M Cost ($)	$ 33,526,272
Fuel Costs	
Fuel Price ($/mmBtu, HHV)	**$ 4.00**
Plant Heat Rate (Btu/kWh)	**6,800**
Annual Fuel Consumption (mmBtu)	28,497,331
Annual Fuel Cost ($)	$ 113,989,325
Unit Cost of Fuel ($/MWh)	$ 27.2
Total Cost of Generating Electricity (2) ($/year)	$ 161,572,177
Total Unit Cost of Electricity ($/MWh)	$ 38.6
Price of Electricity ($/MWh)	**$ 60.0**
Gross Revenue ($)	$ 251,447,040
Pre-tax Profit ($/year)	$ 89,874,863

Notes

(1) Development Costs include professional fees, permitting, interest during construction, startup, initial working capital, and development fees.

(2) The total cost of generating electricity is the sum of the annual financing cost, annual O&M costs, and annual fuel costs.

APPENDIX F: BASELINE ASSUMPTIONS FOR TYPICAL POWER PLANT WITH 100% FINANCING

Plant Output	
Plant Capacity (MW)	**520**
Capacity Factor	**92%**
Annual Generation (MWh/yr)	4,190,784
Installation Costs	
Engineering, Procurement, and Construction Cost ($/kW)	**500**
Engineering, Procurement, and Construction Cost ($)	$ 260,000,000
Development Costs ($/kW) (1)	**200**
Development Costs ($) (1)	$ 104,000,000
Baseline Installation Cost ($/kW)	$ 700
Baseline Installation Cost ($)	$ 364,000,000
Financing Costs	
Debt (% of Installation Cost)	**100%**
Debt	$ 364,000,000
Equity	$ -
Interest Rate	**7.0%**
Term (yr)	**35**
Capital Recovery Factor for Debt Payment	7.72%
Annual Debt Payment ($)	$ 28,113,161
Unit Cost of Debt ($/MWh)	$ 6.7
Owner's Discount Rate	**15.0%**
Project Life (years)	**35**
Capital Recovery Factor for NPV Calculation	15.11%
Operation and Maintenance Costs	
Unit Cost of O & M ($/MWh)	**$ 8.0**
Annual O&M Cost ($)	$ 33,526,272
Fuel Costs	
Fuel Price ($/mmBtu, HHV)	**$ 4.00**
Plant Heat Rate (Btu/kWh)	**6,800**
Annual Fuel Consumption (mmBtu)	28,497,331
Annual Fuel Cost ($)	$ 113,989,325
Unit Cost of Fuel ($/MWh)	$ 27.2
Total Cost of Generating Electricity (2) ($/year)	$ 175,628,758
Total Unit Cost of Electricity ($/MWh)	$ 41.9
Price of Electricity ($/MWh)	**$ 60.0**
Gross Revenue ($)	$ 251,447,040
Pre-tax Profit ($/year)	$ 75,818,282

Notes

(1) Development Costs include professional fees, permitting, interest during construction, startup, initial working capital, and development fees.

(2) The total cost of generating electricity is the sum of the annual financing cost, annual O&M costs, and annual fuel costs.

APPENDIX G: SENSITIVITY OF WASHINGTON POWER PLANT NPV (50% FINANCING)

Gas Price	Electricity Price ($/MWh)										
	$30.0	$40.0	$50.0	$60.0	$70.0	$80.0	$90.0	$100.0	$110.0	$120.0	$130.0
$ 2.00	$ (92)	$ 102	$ 296	$ 491	$ 685	$ 879	$ 1,073	$ 1,267	$ 1,461	$ 1,655	$ 1,849
$ 2.50	$ (160)	$ 34	$ 228	$ 422	$ 616	$ 810	$ 1,004	$ 1,198	$ 1,393	$ 1,587	$ 1,781
$ 3.00	$ (229)	$ (35)	$ 159	$ 353	$ 548	$ 742	$ 936	$ 1,130	$ 1,324	$ 1,518	$ 1,712
$ 3.50	$ (97)	$ (103)	$ 91	$ 285	$ 479	$ 673	$ 867	$ 1,061	$ 1,255	$ 1,450	$ 1,644
$ 4.00	$ (366)	$ (172)	$ 22	$ 216	$ 411	$ 605	$ 799	$ 993	$ 1,187	$ 1,381	$ 1,575
$ 4.50	$ (434)	$ (240)	$ (46)	$ 148	$ 342	$ 536	$ 730	$ 924	$ 1,118	$ 1,312	$ 1,507
$ 5.00	$ (503)	$ (309)	$ (115)	$ 79	$ 273	$ 468	$ 662	$ 856	$ 1,050	$ 1,244	$ 1,438
$ 5.50	$ (571)	$ (377)	$ (183)	$ 11	$ 205	$ 399	$ 593	$ 787	$ 981	$ 1,175	$ 1,370
$ 6.00	$ (640)	$ (446)	$ (252)	$ (58)	$ 136	$ 330	$ 525	$ 719	$ 913	$ 1,107	$ 1,301
$ 6.50	$ (709)	$ (514)	$ (320)	$ (126)	$ 68	$ 262	$ 456	$ 650	$ 844	$ 1,038	$ 1,232
$ 7.00	$ (777)	$ (583)	$ (389)	$ (195)	$ (1)	$ 193	$ 388	$ 582	$ 776	$ 970	$ 1,164
$ 7.50	$ (846)	$ (652)	$ (457)	$ (263)	$ (69)	$ 125	$ 319	$ 513	$ 707	$ 901	$ 1,095
$ 8.00	$ (914)	$ (720)	$ (526)	$ (332)	$ (138)	$ 56	$ 250	$ 445	$ 639	$ 833	$ 1,027

APPENDIX H: SENSITIVITY OF OREGON POWER PLANT NPV (50% FINANCING)

Gas Price	Electricity Price ($/MWh)										
	$ 30.0	$ 40.0	$ 50.0	$ 60.0	$ 70.0	$ 80.0	$ 90.0	$ 100.0	$ 110.0	$ 120.0	$ 130.0
$ 2.00	$ (70)	$ 112	$ 293	$ 474	$ 656	$ 837	$ 1,018	$ 1,199	$ 1,381	$ 1,562	$ 1,743
$ 2.50	$ (131)	$ 50	$ 231	$ 413	$ 594	$ 775	$ 957	$ 1,138	$ 1,319	$ 1,500	$ 1,682
$ 3.00	$ (193)	$ (12)	$ 170	$ 351	$ 532	$ 714	$ 895	$ 1,076	$ 1,257	$ 1,439	$ 1,620
$ 3.50	$ (255)	$ (73)	$ 108	$ 289	$ 471	$ 652	$ 833	$ 1,015	$ 1,196	$ 1,377	$ 1,558
$ 4.00	$ (316)	$ (135)	$ 46	$ 228	$ 409	$ 590	$ 772	$ 953	$ 1,134	$ 1,315	$ 1,497
$ 4.50	$ (378)	$ (196)	$ (15)	$ 166	$ 347	$ 529	$ 710	$ 891	$ 1,073	$ 1,254	$ 1,435
$ 5.00	$ (439)	$ (258)	$ (77)	$ 104	$ 286	$ 467	$ 648	$ 830	$ 1,011	$ 1,192	$ 1,373
$ 5.50	$ (501)	$ (320)	$ (138)	$ 43	$ 224	$ 405	$ 587	$ 768	$ 949	$ 1,131	$ 1,312
$ 6.00	$ (563)	$ (381)	$ (200)	$ (19)	$ 162	$ 344	$ 525	$ 706	$ 888	$ 1,069	$ 1,250
$ 6.50	$ (624)	$ (443)	$ (262)	$ (80)	$ 101	$ 282	$ 463	$ 645	$ 826	$ 1,007	$ 1,189
$ 7.00	$ (686)	$ (505)	$ (323)	$ (142)	$ 39	$ 220	$ 402	$ 583	$ 764	$ 946	$ 1,127
$ 7.50	$ (748)	$ (566)	$ (385)	$ (204)	$ (22)	$ 159	$ 340	$ 521	$ 703	$ 884	$ 1,065
$ 8.00	$ (809)	$ (628)	$ (447)	$ (265)	$ (84)	$ 97	$ 278	$ 460	$ 641	$ 822	$ 1,004

APPENDIX I: SENSITIVITY OF CALIFORNIA POWER PLANT NPV (50% FINANCING)

Gas Price	Electricity Price ($/MWh)										
	$ 30.0	$ 40.0	$ 50.0	$ 60.0	$ 70.0	$ 80.0	$ 90.0	$ 100.0	$ 110.0	$ 120.0	$ 130.0
$ 2.00	$ (82)	$ 95	$ 271	$ 448	$ 625	$ 802	$ 979	$ 1,156	$ 1,333	$ 1,510	$ 1,687
$ 2.50	$ (143)	$ 34	$ 211	$ 388	$ 565	$ 742	$ 919	$ 1,096	$ 1,273	$ 1,450	$ 1,627
$ 3.00	$ (203)	$ (26)	$ 151	$ 328	$ 505	$ 682	$ 859	$ 1,036	$ 1,213	$ 1,390	$ 1,567
$ 3.50	$ (263)	$ (86)	$ 91	$ 268	$ 445	$ 622	$ 799	$ 976	$ 1,153	$ 1,330	$ 1,507
$ 4.00	$ (323)	$ (146)	$ 31	$ 208	$ 385	$ 562	$ 739	$ 916	$ 1,092	$ 1,269	$ 1,446
$ 4.50	$ (383)	$ (206)	$ (29)	$ 148	$ 325	$ 501	$ 678	$ 855	$ 1,032	$ 1,209	$ 1,386
$ 5.00	$ (443)	$ (266)	$ (90)	$ 87	$ 264	$ 441	$ 618	$ 795	$ 972	$ 1,149	$ 1,326
$ 5.50	$ (504)	$ (327)	$ (150)	$ 27	$ 204	$ 381	$ 558	$ 735	$ 912	$ 1,089	$ 1,266
$ 6.00	$ (564)	$ (387)	$ (210)	$ (33)	$ 144	$ 321	$ 498	$ 675	$ 852	$ 1,029	$ 1,206
$ 6.50	$ (624)	$ (447)	$ (270)	$ (93)	$ 84	$ 261	$ 438	$ 615	$ 792	$ 969	$ 1,146
$ 7.00	$ (684)	$ (507)	$ (330)	$ (153)	$ 24	$ 201	$ 378	$ 555	$ 731	$ 908	$ 1,085
$ 7.50	$ (744)	$ (567)	$ (390)	$ (213)	$ (36)	$ 141	$ 317	$ 494	$ 671	$ 848	$ 1,025
$ 8.00	$ (804)	$ (627)	$ (450)	$ (274)	$ (97)	$ 80	$ 257	$ 434	$ 611	$ 788	$ 965

APPENDIX J: SENSITIVITY OF WASHINGTON POWER PLANT NPV (100% FINANCING)

Gas Price	Electricity Price ($/MWh)										
	$ 30.0	$ 40.0	$ 50.0	$ 60.0	$ 70.0	$ 80.0	$ 90.0	$ 100.0	$ 110.0	$ 120.0	$ 130.0
$ 2.00	$ 62	$ 256	$ 450	$ 644	$ 839	$ 1,033	$ 1,227	$ 1,421	$ 1,615	$ 1,809	$ 2,003
$ 2.50	$ (6)	$ 188	$ 382	$ 576	$ 770	$ 964	$ 1,158	$ 1,352	$ 1,546	$ 1,741	$ 1,935
$ 3.00	$ (75)	$ 119	$ 313	$ 507	$ 701	$ 896	$ 1,090	$ 1,284	$ 1,478	$ 1,672	$ 1,866
$ 3.50	$ (143)	$ 51	$ 245	$ 439	$ 633	$ 827	$ 1,021	$ 1,215	$ 1,409	$ 1,603	$ 1,798
$ 4.00	$ (212)	$ (18)	$ 176	$ 370	$ 564	$ 759	$ 953	$ 1,147	$ 1,341	$ 1,535	$ 1,729
$ 4.50	$ (281)	$ (86)	$ 108	$ 302	$ 496	$ 690	$ 884	$ 1,078	$ 1,272	$ 1,466	$ 1,660
$ 5.00	$ (349)	$ (155)	$ 39	$ 233	$ 427	$ 621	$ 816	$ 1,010	$ 1,204	$ 1,398	$ 1,592
$ 5.50	$ (418)	$ (224)	$ (29)	$ 165	$ 359	$ 553	$ 747	$ 941	$ 1,135	$ 1,329	$ 1,523
$ 6.00	$ (486)	$ (292)	$ (98)	$ 96	$ 290	$ 484	$ 678	$ 873	$ 1,067	$ 1,261	$ 1,455
$ 6.50	$ (555)	$ (361)	$ (166)	$ 28	$ 222	$ 416	$ 610	$ 804	$ 998	$ 1,192	$ 1,386
$ 7.00	$ (623)	$ (429)	$ (235)	$ (41)	$ 153	$ 347	$ 541	$ 735	$ 930	$ 1,124	$ 1,318
$ 7.50	$ (692)	$ (498)	$ (304)	$ (109)	$ 85	$ 279	$ 473	$ 667	$ 861	$ 1,055	$ 1,249
$ 8.00	$ (760)	$ (566)	$ (372)	$ (178)	$ 16	$ 210	$ 404	$ 598	$ 793	$ 987	$ 1,181

APPENDIX K: SENSITIVITY OF OREGON POWER PLANT NPV (100% FINANCING)

Gas Price	Electricity Price ($/MWh)										
	$ 30.0	$ 40.0	$ 50.0	$ 60.0	$ 70.0	$ 80.0	$ 90.0	$ 100.0	$ 110.0	$ 120.0	$ 130.0
$ 2.00	$ 86	$ 268	$ 449	$ 630	$ 811	$ 993	$ 1,174	$ 1,355	$ 1,537	$ 1,718	$ 1,899
$ 2.50	$ 25	$ 206	$ 387	$ 568	$ 750	$ 931	$ 1,112	$ 1,294	$ 1,475	$ 1,656	$ 1,837
$ 3.00	$ (37)	$ 144	$ 326	$ 507	$ 688	$ 869	$ 1,051	$ 1,232	$ 1,413	$ 1,595	$ 1,776
$ 3.50	$ (99)	$ 83	$ 264	$ 445	$ 626	$ 808	$ 989	$ 1,170	$ 1,352	$ 1,533	$ 1,714
$ 4.00	$ (160)	$ 21	$ 202	$ 384	$ 565	$ 746	$ 927	$ 1,109	$ 1,290	$ 1,471	$ 1,653
$ 4.50	$ (222)	$ (41)	$ 141	$ 322	$ 503	$ 684	$ 866	$ 1,047	$ 1,228	$ 1,410	$ 1,591
$ 5.00	$ (284)	$ (102)	$ 79	$ 260	$ 442	$ 623	$ 804	$ 985	$ 1,167	$ 1,348	$ 1,529
$ 5.50	$ (345)	$ (164)	$ 17	$ 199	$ 380	$ 561	$ 742	$ 924	$ 1,105	$ 1,286	$ 1,468
$ 6.00	$ (407)	$ (226)	$ (44)	$ 137	$ 318	$ 500	$ 681	$ 862	$ 1,043	$ 1,225	$ 1,406
$ 6.50	$ (469)	$ (287)	$ (106)	$ 75	$ 257	$ 438	$ 619	$ 801	$ 982	$ 1,163	$ 1,344
$ 7.00	$ (530)	$ (349)	$ (168)	$ 14	$ 195	$ 376	$ 558	$ 739	$ 920	$ 1,101	$ 1,283
$ 7.50	$ (592)	$ (411)	$ (229)	$ (48)	$ 133	$ 315	$ 496	$ 677	$ 859	$ 1,040	$ 1,221
$ 8.00	$ (653)	$ (472)	$ (291)	$ (110)	$ 72	$ 253	$ 434	$ 616	$ 797	$ 978	$ 1,159

APPENDIX L: SENSITIVITY OF CALIFORNIA POWER PLANT NPV (100% FINANCING)

Gas Price	Electricity Price ($/MWh)										
	$ 30.0	$ 40.0	$ 50.0	$ 60.0	$ 70.0	$ 80.0	$ 90.0	$ 100.0	$ 110.0	$ 120.0	$ 130.0
$ 2.00	$ 83	$ 260	$ 437	$ 614	$ 791	$ 968	$ 1,145	$ 1,322	$ 1,499	$ 1,676	$ 1,853
$ 2.50	$ 23	$ 200	$ 377	$ 554	$ 731	$ 908	$ 1,085	$ 1,262	$ 1,439	$ 1,616	$ 1,793
$ 3.00	$ (37)	$ 140	$ 317	$ 494	$ 671	$ 848	$ 1,025	$ 1,202	$ 1,379	$ 1,556	$ 1,732
$ 3.50	$ (97)	$ 80	$ 257	$ 434	$ 611	$ 788	$ 965	$ 1,141	$ 1,318	$ 1,495	$ 1,672
$ 4.00	$ (157)	$ 20	$ 197	$ 374	$ 550	$ 727	$ 904	$ 1,081	$ 1,258	$ 1,435	$ 1,612
$ 4.50	$ (217)	$ (41)	$ 136	$ 313	$ 490	$ 667	$ 844	$ 1,021	$ 1,198	$ 1,375	$ 1,552
$ 5.00	$ (278)	$ (101)	$ 76	$ 253	$ 430	$ 607	$ 784	$ 961	$ 1,138	$ 1,315	$ 1,492
$ 5.50	$ (338)	$ (161)	$ 16	$ 193	$ 370	$ 547	$ 724	$ 901	$ 1,078	$ 1,255	$ 1,432
$ 6.00	$ (398)	$ (221)	$ (44)	$ 133	$ 310	$ 487	$ 664	$ 841	$ 1,018	$ 1,195	$ 1,372
$ 6.50	$ (458)	$ (281)	$ (104)	$ 73	$ 250	$ 427	$ 604	$ 781	$ 957	$ 1,134	$ 1,311
$ 7.00	$ (518)	$ (341)	$ (164)	$ 13	$ 190	$ 366	$ 543	$ 720	$ 897	$ 1,074	$ 1,251
$ 7.50	$ (578)	$ (401)	$ (225)	$ (48)	$ 129	$ 306	$ 483	$ 660	$ 837	$ 1,014	$ 1,191
$ 8.00	$ (639)	$ (462)	$ (285)	$ (108)	$ 69	$ 246	$ 423	$ 600	$ 777	$ 954	$ 1,131